Information Request DTE-6-3

Reference Article 2.2 of the Settlement Agreement. The Company states that, "the Default Service deferral set forth on Exhibit BEC-RAP-1 (Settlement) pages 1 and 3, is reduced by $368,728 to incorporate the net cost impact relating to the class-action suit . . . involving whether certain customers should have been receiving Standard Offer Service rather than Default Service." The Company further states that, "the adjustment to the 2002 Default Service Deferral Balance is the full unmitigated cost plus carrying charges borne by Default Service customers resulting from reclassification of customers who were categorized inappropriately as Default Service customers."

(a) Please provide all supporting calculations, schedules and work papers that indicate how the amount of $368,728 was derived.
(b) Provide the total number of Boston Edison customers that were reclassified from Default Service to Standard Offer Service. Provide the total revenue refunded to reclassified customers in 2002.
(c) Provide the total revenue refunded to reclassified customers in 2003 to date.

Supplemental Response

During a conference call with Department staff, the Company was asked to clarify the initial response to this Information Request by explaining the manner by which supplier costs are reconciled by the ISO. In addition, the Department requested that the Company clarify why the reconciliation process for January through July 2001 did not reconcile the supplies for the customers who were misclassified as Default Service customers.

The ISO settlement process generally establishes the means by which loads and supplies are reconciled after the fact. Attachment DTE-6-3(b) is a copy of the internal NSTAR Electric document that explains the load estimation and reconciliation process. Attachment DTE-6-3(c) is an excerpt from ISO Manual 29, which explains the reconciliation process.

In the context of this Information Request, where the Company was able to include the reclassification of customer classes before the close of the ISO settlement time, the ISO reconciliation process ensured that the correct supplier was paid the correct amount for power supplied. As indicated in Attachment DTE-6-3(a)(1), beginning August 2001, the supplier costs associated with the class-action reclassification were fully reconciled and there was no cost impact.

However, all costs were not fully reconciled for the period January 2001 through July 2001. The magnitude of the cost differential was small until July 2001, and the unreconciled difference in July amounted to $319,440 (of the total $344,924). See Attachment DTE-6-3(a)(1), page 5, Column 9. The largest component of this difference was the large increase in the cost of Default Service that became effective in July 2001. The average cost of Default Service for the first half of 2001 was approximately 6.4 cents per kWh and the cost in July 2001 was approximately 10.1 cents per kWh.

Response

(a) The net cost impact relating to the class action on behalf of customers who should have been receiving Standard Offer Service rather than Default Service was $344,924 plus carrying charges of $23,804. It should be noted that the remedies implemented by the Company ensured that customer bills were properly adjusted and that the revenue changes flowed through to the revenue figures included in the reconciliation schedules filed with the Department. In addition, there was a potential difference in the costs incurred by the Company in serving customers because of differing supply contracts associated with procuring electricity for Default Service and Standard Offer Service. However, as described below, much of the differences was corrected through the normal ISO reconciliation process so that the total costs included in the schedules are as they would have been if the customers were on the correct rate throughout. In some instances, the cost differences were not corrected and the $344,924 represents all of the increased costs associated with customers being misclassified.

A description of the calculations for the cost and carrying charges follows and is shown in Attachment DTE-6-3(a)(1) and Attachment DTE-6-3(a)(2), respectively.

Attachment DTE-6-3(a)(1)

NSTAR Electric cancelled and re-billed customers beginning in October 2001 and continued through December 2001. Based on the class action suit the number of customers, the net KWH transferred, and the net dollar impact is shown in Section 1. Note that column 12 identifies the net KWH re-billed equals 131 GWH.

NSTAR Electric knows that all its distribution companies were affected and Boston Edison had the largest number of customers affected. It was assumed that the disposition of re-billed KWH followed the 2001 monthly trend. NSTAR Electric used the 2001 monthly KWH reports provided to DOER to allocate the re-billed KWH as shown in Section 3.

Section 4 summarizes the allocation of load by month.

Section 5 sums the allocation results from Section 4 and applies the class percentage splits per Section 2.

Section 6 adjusts sales from Section 5 by losses to determine the monthly customer class loads.

During 2001, NSTAR Electric's normal load reconciliation process with the ISO allowed the post-July 2001 load transfers between Standard Offer and Default Service to be reflected. The impact of this is that post-July 2001 transfers and the associated cost differences have already been reflected.

Section 7 reflects the Company's preliminary adjustments for the January through May period, the period prior to the Company filing final reconciled loads with the ISO.

Section 8 reflects the sum of the class loads plus the preliminary adjustments.

Section 9 reflects the results of the Company' s examination of Standard Offer hourly load records for January though July 2001 to determine the percentage of load that occurred in the peak and off-peak periods.

Section 10 summarizes incremental Standard Offer energy cost. Standard Offer load was allocated between the peak and the off-peak period. The Standard Offer peak period supply price was assumed to be the actual monthly average strip prices, the Standard Offer off-peak period supply price was assumed to be the monthly average off-peak hourly ISO clearing price.

Section 11 identifies the Default Service supply price per the effective contracts and incremental DS cost.

Section 12, identifies for NSTAR Electric, as well as each distribution company, the net impact to expenses. Boston Edison's $344,924 cost impact appears on line 174.

Attachment DTE-6-3(a)(2)

Attachment DTE-6-3(a)(2) computes interest at the appropriate rate for Default Service deferrals from July 2001 through December 2002. The total interest is approximately $23,804.

(b) The reclassification of customers resulting from the class-action suit was completed in 2001.

(c) The reclassification of customers resulting from the class-action suit was completed in 2001.

NSTAR LOAD ESTIMATION AND RECONCILIATION UNDER SMD

1. General Description

Each business day, NSTAR calculates its territory loads for every hour of the previous day(s) using actual hourly generation and interchange metered values. The territory loads are defined as the total customer load plus non-PTF transmission and distribution losses for the Load Zones within each service territory (Boston Edison NEMA, Boston Edison SEMA, Commonwealth (SEMA) & Cambridge (NEMA)). The territory loads are then input to the Load Estimation process.

Load Estimation at NSTAR ELECTRIC is billing account based. For each active account for the day to be estimated, a daily billing load is developed. This is accomplished in one of two ways. First, if the account has been billed, the latest bill information (account, number of billing days, total kWh, supplier ID) is used to compute a daily average use (total kWh/number of billing days). Second, if the account is active but has not been billed (new account), a daily rate average is used. The daily rate average is based on the past 24 months billing for all customers by rate.

The billing file used in this process is a SAS dataset created each day upon the completion of nightly cycle billing through the Customer Information System ("CIS"). This SAS dataset combines three of the four Companies' billing systems, computer billed accounts, time-of-use billed accounts, and special ledger accounts, into one file. A fourth billing system, municipal lighting, is incorporated by the load estimation process. The SAS dataset and municipal lighting files include the Load Zone assignment for each account.

Once daily billing loads are developed using the CIS data, line losses are added to each account. The losses are by rate code and are based on NSTAR studies. Adding the line losses to the daily billing load for each account creates the daily load for estimation per account.

Load shapes are applied to the daily load for estimation per account. The load shapes are based on load research data and are broken into weekday load shape and weekend load shape. The application of the load shape distributes the daily load for estimation for each account over 24 hours.

Telemetered accounts (when available) are eliminated at this point. Telemetered accounts are added back later in the process.

Account loads for estimation are then aggregated by supplier ID by Load Zone. When telemetered load is available, it will be scaled for line losses and added back in at this point. Hourly ratios are now developed for each supplier based on the suppliers estimated total load to the total estimated load within each Load Zone.

Metered wholesale load is subtracted from the total territory load (for each Load Zone) for purposes of estimation. The hourly supplier ratios developed from CIS data are applied to the net territory load (for each Load Zone) to calculate each supplier's contribution to the Load Zone load. Metered wholesale load is then added back into the total.

Final estimated supplier values (by Load Zone) are then posted to the ISO Reporting Application ("IRA") System for transmission to ISO-NE.

2. Reporting Of Suppliers' Loads To The ISO

The total hourly load estimates for each supplier's Load Assets are reported to the ISO-NE, in accordance with the ISO standards, for use in the ISO wholesale settlement process.

3. Monthly Reconciliation

Under SMD, the ISO's meter adjustment process requires the re-submittal of hourly data. Territory loads (by Load Zone) may change due to corrections to hourly generation and interchange metered values. Note: the day after reporting of loads may have required directly metered values to be estimated because of equipment / communication problems. These changes will be submitted to the ISO within a 45 day period following the ISO's bill for the month. For example, if the ISO issues its March 2003 bill on April 15, Participants must submit revised hourly data for interchange metering by May 30, 2003. The revised hourly meter data will result in changes to NSTAR's calculated hourly territory load values (Boston Edison NEMA, Boston Edison SEMA, Commonwealth (SEMA) & Cambridge (NEMA)). Revised territory loads are then input to the Load Reconciliation process.

Suppliers' estimated loads must be reconciled to their customers' metered usage and submitted to the ISO 80 days after the ISO's bill for the month. Each distribution company uses customers' actual meter readings, to the extent that they are available, to re-estimate each supplier's hourly loads (by Load Zone) and report the appropriate load assets to the ISO.

The reconciliation methodology is same as the load estimation methodology (actual billing data used instead of latest billing data).

For time of use customers, the actual interval data for the calendar month will be used for reconciliation when available.

Each supplier's reconciled hourly loads are reported to the ISO for resettlement.

4. ICAP

SMD also requires ICAP contributions (by Load Asset) to be calculated each day based on the previous power year's historical peak. Reference Market Rule 1 and related Market Manuals for specific details.

9.1.1 Data Reconciliation Process

The Assigned Meter Reader or Host Participant provides the ISO all meter data required to carry out the re-settlement process to account for actual meter readings. Participants provide the ISO all Internal Bilateral Transaction data required to carry out the re-settlement process to account for actual transactions. The Assigned Meter Readers, Host Participants, and Participants provide the ISO with such data in accordance with the timelines and process defined below. For the purpose of describing the reconciliation re-settlement deadlines, the days referenced are the first business day following the number of (calendar) days cited after the Customer Bill was issued for the month:

1) Prior to the 45th day, Assigned Meter Readers must submit hourly meter data for all directly metered assets. When resubmitting hourly data, all hours of the day must be submitted to the ISO, no partial-day data will be accepted for re-settlement. After the 45th day, the directly metered asset data received by ISO-NE will not be accepted from the Assigned Meter Readers.

2) During days 46 through 59, the Host Participant reviews the directly metered asset data provided by the ISO to the Host Participant. If an error is discovered with the directly metered asset data, the Host Participant and the Assigned Meter Reader will work together to determine the correct hourly data. Corrected meter data shall be supplied to ISO New England using the following procedure:

(a) The Assigned Meter Reader sends an e-mail containing a file upload, of the agreed upon corrected meter data, to the Host Participant.
(b) The Host Participant forwards the e-mail, containing the agreed upon data, to ISO New England's Customer Services and Training Department (custserv@iso-ne.com) and copies the Assigned Meter Reader
(c) The Assigned Meter Reader submits to the ISO's Customer Services and Training Department a "confirming response" for the corrected Meter Data e-mail containing "Confirmed contents please upload file in the body of the "confirming response" e-mail.
(d) ISO New England will not use the revised hourly values in the settlement system until positive confirmation is received from the Assigned Meter Reader.

3) On the 60th day, the ISO will not accept any revisions to the directly metered asset data for use in the meter reconciliation re-settlement process.

4) Prior to the 80th day, Host Participant Assigned Meter Readers must submit meter data for all indirectly metered Load Assets. Also prior to the 80th day, the Host Participant Assigned Meter Readers will provide the ISO with the final ICAP daily tags for use in the ICAP load shifting re-settlement. Data will not be accepted by the ISO from the Host Participant after the 80th day.

5) By the 90th day, Participants submit new Internal Bilateral Transactions applicable to the Real-Time Energy Market or revisions to Internal Bilateral Transaction data for the Real-Time Energy Market to the ISO before 5:00 p.m.